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SUMMARY

An integrated coal-gasifier combined-cycle (IGCC) system which simultaneously produces electricty, process steam and liquid hydrogen was evaluated. This is a modification of previously studied IGCC systems which cogenerate electricity and process steam for industrial applications. The extension of the IGCC cogeneration system to produce more than two useful products is referred to here as an IGCC polygeneration system. In a polygeneration system, part of the clean fuel gas produced by the gasifier subsystem is used as feedstock for hydrogen production. Liquid hydrogen production rates spanning the possible needs of the Space Shuttle were considered. For industrial applications, other clean fuels or chemical feedstocks could be produced by an IGCC polygeneration plant.

A number of IGCC polygeneration plants were considered. All of them use a 15 MWe gas turbine, which is representative of commerically available small state-of-the-art turbines. The liquid hydrogen production rate was varied from 0 to 20 tons per day and the process heat from 0 to 20 MWt. The electrical output varied from 8 to 22 MWe depending on the amounts of the other two products.

For each of the plants considered, the revenue required to own and operate the plant is compared with the potential market value of the products. The potential market value of the products is found to be substantially greater than the revenue required for a wide range of economic assumptions. This indicates that a higher return to the owner, than the target value assumed for calculating the revenue required, could be achieved or that the products could be generated at a cost substantially lower than their assumed market value.

The margin between the revenue required and the product market value is much larger for polygeneration plants than for otherwise similar cogeneration plants producing only electricity and steam. The margin also increases with time at a rate which depends on the relative cost escalation of coal, electricity, oil, and liquid hydrogen.

INTRODUCTION

Integrated coal-gasifier combined-cycle (IGCC) systems have potential advantages over current state-of-the-art coal or oil/gas fired systems in both electric utility and industrial cogeneration applications. Compared to coal-fired steam powerplants with flue-gas desulfurization, IGCC systems have the potential for higher efficiency with competitive capital cost and would produce significantly lower amounts of waste products and environmental emis-

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sions. A conceptual design of an IGCC powerplant to supply the nominally 20 MWe base-load electric requirements and the steam requirements of NASA Lewis Research Center is presented in reference 1. The performance and operating economics of this cogeneration system were further analyzed in reference 2. Although both the electric and steam loads at the Lewis Research Center vary considerably in time, the analysis indicated the potential for considerable energy and operating cost savings. These savings result primarily from the recovery of otherwise waste heat to produce the required process steam, thus avoiding the purchase and use of natural gas to provide this steam. The environmentally clean characteristics of an IGCC powerplant and the modular construction provide the potential to achieve the energy and cost savings of coal based cogeneration in relatively small dispersed industrial applications.

IGCC systems provide the further opportunity to extend the cogeneration concept by simultaneously providing useful products in addition to electricity and process steam. Some of the cleaned fuel gas produced by the coal gasifier subsystem could be used directly to meet industrial site needs or could be further processed to provide a wide variety of fuels or chemical feedstocks. Whether or not this is attractive depends on the value of the additional product compared to the incremental increase in the IGCC system capital and operating costs required to produce the additional product. The purpose of this report is to evaluate the potential benefits of an IGCC system configured to simultaneously produce electricity, process heat and a coal-derived fuel and to compare it to an IGCC system configured to cogenerate electricity and process heat. The analysis is based on modifications of the IGCC cogeneration system studied in references 1 and 2. The fuel product considered in this analysis is liquid hydrogen. The liquid hydrogen production rates considered span the range of projected requirements for Space Shuttle propellant.

Liquid hydrogen was considered because:

(1) its supply and cost are significant to NASA and of particular interest for the Space Shuttle;

(2) its current production methods require natural gas or oil feedstock which are expected to rise significantly in cost;

(3) its production requires significant amounts of steam and power, and hence there is the opportunity to achieve large performance and cost benefits from combining its production with an IGCC cogeneration system.

Part of the gasifier output would be used for hydrogen production feedstock, and part of the combined cycle output would supply the hydrogen production power and steam requirements. This extension of the IGCC cogeneration system to provide more than two products is referred to here as an IGCC polygeneration system.

For the relatively small-size IGCC systems which would be of interest for dispersed industrial cogeneration or polygeneration applications there are a limited number of existing and attractive gas turbines which can be used (see ref. 1). If the system design is constrained by the available turbomachinery sizes, it is unlikely that the net polygeneration system electric output would exactly match the requirement of a particular site. Similarly it

is unlikely that the gross electric generation capacity could be made to just match the power requirement of hydrogen production if it were desired to produce only hydrogen with no net electric power output. In fact, for the gas turbine sizes considered in references 1 and 2, efficiently configured IGCC systems all result in net power output for the range of hydrogen production rates of interest. The approach taken in this analysis was to consider a single gas turbine capacity (15 MWe) and to compare IGCC systems using that turbine for a parametric range of liquid hydrogen output rates (0 to 20 ton/day) and of net process steam output rates (0 to 20 MWt). The net electric power output rate decreases with increasing hydrogen and/or process heat outputs. For the cases considered, the net electric power output of the system varies from about 22 MWe to about 8 MWe. This range of IGCC polygeneration cases is compared on the basis of performance and economics. The results are not specifically related to a particular site. However, the comparisons are made for a wide enough range of economic ground rules and assumptions to permit useful comparisons to be made for specific site conditions.

DESCRIPTION OF IGCC SYSTEMS

A schematic diagram of an IGCC cogeneration system is shown in figure 1(a). The overall system is divided into the gasification/clean-up and the combined-cycle subsystems. The major components of the gasification/clean-up subsystem are the coal gasifier, the air separation unit to supply pressurized oxygen to the gasifier, the cold-gas desulfurization unit, and the heat exchangers required to cool the raw fuel gas prior to the desulfurization step. This subsystem produces a clean, pressurized, preheated fuel gas which consists mainly of carbon monoxide, hydrogen, carbon dioxide, and water vapor. In addition, part of the sensible heat of the raw fuel gas produced by the gasifier is used to generate high pressure steam which is used in the steam turbine of the combined-cycle subsystem. The power required by the air and oxygen compressors of the air-separation plant is the largest of the plant auxiliary power requirements supplied from the output of the combined cycle. Waste outputs or potentially useful byproducts from the gasification subsystem include gaseous nitrogen from the air-separation unit, elemental sulfur from the desulfurization unit, and ash from the gasifier.

Electric power is produced by both the gas turbine and the steam turbine of the combined-cycle subsystem. As indicated, part of the power is used internally for plant auxiliaries. Most of the steam turbine throttle steam is generated in the gas turbine exhaust heat recovery heat exchanger. The remainder is obtained from the raw-fuel-gas coolers of the gasification subsystem. The process steam is extracted as required from the steam turbine.

The system is modified to also produce liquid hydrogen as shown in figure 1(b). The IGCC polygeneration system consists of the same two major subsystems of the cogeneration plant with the addition of a liquid hydrogen production subsystem. Part of the cleaned fuel gas is diverted to this subsystem for hydrogen production using conventional technology equipment. The carbon monoxide in the fuel gas is reacted with steam extracted from the steam turbine to produce additional hydrogen and carbon dioxide. The carbon dioxide is scrubbed from the gas stream and the gaseous hydrogen is then liquified. The compression power required to liquify the hydrogen and convert it to the equilibrium parahydrogen form is supplied by the combined-cycle subsystem.

The IGCC system parameters for the analysis are shown in table I. An oxygen-blown, entrained-bed gasifier was chosen because of the availability of performance and cost estimates from previously published studies. It is representative of the potentially attractive gasifiers for such applications, but a comparison of IGCC polygeneration systems using different gasifiers was not made. An oxygen-blown gasifier was employed so that the fuel gas input to the hydrogen production subsystem is free of nitrogen. The gas turbine inlet temperature, pressure ratio, and size reflect current state-of-the-art and commercially available equipment (ref. 1). Steam is extracted from the steam turbine at two pressure levels. The higher extraction pressure is sufficiently above the fuel gas pressure in the shift reactor of the hydrogen production subsystem. The 200 psi extraction provides steam at a high enough temperature and pressure to meet the majority of potential requirements for industrial process steam or heating (ref. 3).

To evaluate the IGCC polygeneration configuration of figure 1(b) compared to the cogeneration configuration of figure 1(a), the amount of hydrogen produced and the amount of net process steam were parametrically varied as indicated in the table. Zero hydrogen production represents the cogeneration configuration of figure 1(a). The range from 10 to 20 tons per day liquid hydrogen brackets the projected requirements of the Space Shuttle in the late 1980's, and is typical of the size of existing natural-gas-fueled liquid hydrogen commercial production facilities. The net process steam was varied as shown. The 20 MWt value approaches the maximum extraction rate for the size systems studied. Since there is not a continuum of sizes of appropriate gas turbines commercially available, the approach taken was to fix the gas turbine size at 15 MWe. This is representative of the gas turbines analyzed in references 1 and 2. At zero hydrogen production rate, the total system performance and output are similar to the cogeneration system studied in reference 2. The major difference is that an air blown gasifier was assumed for the application considered in reference 2.

STUDY APPROACH

Three different IGCC plants were considered, corresponding to the liquid hydrogen production rates of 20, 10, and 0 tons per day as shown in table I. These plants were designated respectively as plants A, B, and C. Each plant was analyzed for three net steam extraction rates, that is, 0, 10, and 20 MWt. A total of nine cases was thus considered. These are listed in table II.

As discussed in the previous section, each of the IGCC plants studied used a 15 MWe gas turbine. The gasification subsystem is sized to produce the cleaned fuel gas required to operate the gas turbine at full capacity and to produce the fuel gas required for the assumed LH_2 output rates. The relative size of the gasification subsystem in each plant is indicated by the coal input rates given in table II. The steam turbine and its electrical generator are sized to accomodate the total steam produced in the gas-turbine-exhaust heat-recovery heat exchanger and in the fuel-gas cooler. When no steam is extracted from the steam turbine, the total power produced by the gas turbine and the steam turbine for the three IGCC plants is the gross power rating shown in table II. The gross power rating is slightly higher for plant A compared to B and C because the larger gasification subsystems produce more steam in the fuel-gas cooler. When steam is extracted from the steam turbine for use in the hydrogen production subsystem and/or for external process use, the total

power produced is lowered. Also, as was indicated in figure 1, part of the system gross power output is used to meet auxiliary power requirements including the air-separation unit in the gasification subsystem and the compressors for hydrogen liquefaction. The net system power output for the IGCC plants studied are shown in table II. For each plant, the net power output is given as a function of the amount of net process steam extracted for external process use. The net power output is lowest for plant A, which produces the most liquid hydrogen, since this plant requires the most steam extraction for hydrogen production and the most auxiliary power for air-separation-plant drive and hydrogen liquefaction.

In addition to estimates of the performance of the nine cases considered, the capital and operating costs of the three plants in table II were estimated. However, the comparative evaluation of these three IGCC plants is complicated by the fact that they produce different amounts of multiple products. Therefore, a comparison of single characteristics such as efficiency, amount of fuel used, operating cost, or capital cost is incomplete. An evaluation based on a comparison of their overall economic attractiveness is more appropriate. This leads to consideration of various parameters which relate the capital investment required, the cost of operation, and the potential market value of the products generated. In this study the IGCC systems were not evaluated as alternative investments that are each configured to meet the same requirement of a specific site or application. Therefore, such criteria as payback period or discounted cash flow analysis which lead to site or owner specific assumptions were not used. In this study the emphasis is on a parametric comparison of the polygeneration configuration represented by plants A and B and the cogeneration configuration of plant C. The approach taken was to simply compare the potential total market value of all the products generated to the annual revenue requirement of the system that would provide an investor with a target return on equity. This revenue requirement includes all operating costs (including coal), maintenance costs, and all capital related costs (such as capital recovery, return on equity, interest on debt, Federal and State taxes, and insurance). The margin between the revenue required by each plant and the potential market value of the products it generates is used as an indicator of the relative attractiveness of the IGCC plants. The sensitivities of the economic comparisons to changes in economic and market conditions were also analyzed.

SYSTEM PERFORMANCE

A heat and mass balance was calculated for each of three cases of the three IGCC plants to the level of detail indicated by the schematic diagrams in figure 1. The relationships among the major subsystems are shown by the energy flow diagrams in figure 2. The diagrams shown are for case 2 (10 MW of net process steam) of each of the three plants. The diagrams for the other two cases of each plant differ from the case 2 diagram in only a few respects. These differences will be discussed below. The value of the energy flows are given in megawatts. They indicate the sum of the heating value and the sensible and latent energy of flow streams between subsystems, the sensible energy transferred by heat exchangers between subsystems, or electric power transferred between subsystems. Various losses from the subsystems are also shown.

These diagrams demonstrate quantitatively many of the points that have already been made about the changes in energy flows between subsystems as the

IGCC plant is sized to produce different amounts of liquid hydrogen. As the amount of liquid hydrogen produced is increased, the diagrams of figure 2 show that the IGCC plant:

(1) will have a larger gasifier subsystem to produce the additional fuel gas needed for liquid hydrogen production;

(2) will produce more steam in the gasifier subsystem for use in the combined cycle which leads to a larger steam turbine;

(3) will require more steam to be extracted from the steam turbine for use in the hydrogen production subsystem;

(4) will have a greater portion of the gross electrical power used for internal purposes in the air-separation unit of the gasifier subsystem and for hydrogen liquefaction.

The energy flow diagrams for cases 1 and 3 for each plant differ from the diagrams for case 2 in only the energy flow in the net process steam extracted, the power produced by the steam turbine (and, hence, the net power), and the heat rejected from the combined cycle. The diagrams for cases 1 and 3 may be easily constructed using information in table II.

Inspection of figure 2 also shows that if the amount of liquid hydrogen produced by IGCC plants using a fixed gas turbine is increased, there will be some hydrogen production rate at which all the electric power generated by the combined-cycle system will be required internally within the plant. For the 15 MWe gas turbine used here, this situation occurs for a liquid hydrogen production rate of about 47 tons per day if there is no net process steam extraction, and for a production rate of about 37 tons per day if the net process steam extraction is 20 MW.

Figure 3 is a comparison of the amount of coal required by the IGCC polygeneration systems studied and the amounts of fuels which would be required to produce the same products in a conventional manner. The coal consumption for the IGCC polygeneration cases correspond to the data in table II. The conventional cases assume the use of natural gas as the feedstock and the fuel for gaseous hydrogen production and the use of electric power purchased from a utility for hydrogen liquefaction. The natural gas and electric requirements for conventional commercial liquid hydrogen production are obtained from references 4 and 5. The amount of fuel required at the utility power system sites to provide electricity equal to the net power output of the IGCC system and for hydrogen liquefaction was calculated assuming an overall utility system efficiency of 32 percent. The amount of oil or gas boiler fuel which would be displaced by the net steam output of the IGCC system was calculated assuming a boiler efficiency of 85 percent.

The figure illustrates the potential fuel energy savings of an IGCC polygeneration system. Comparison of plant C to plants A and B indicates that the fuel savings is basically the result of the cogeneration of process steam and electricity by the combined cycle system. It is likely, however, that these polygeneration results are conservative because of simplifications made in the present performance analysis. For example, the shift reaction is exothermic. In the present study the heat released was assumed to be wasted,

while in existing processes this heat is utilized. Also in the present analysis, the methane content of the fuel gas was assumed not to contribute to the hydrogen production. Such simplifying assumptions should be examined in any further studies.

In addition to the fuel savings, figure 3 illustrates a displacement of oil and natural gas, typically used for production of process steam and liquid hydrogen, by the use of coal in the IGCC system. The use of coal provides the IGCC polygeneration system a significant operating cost savings with potentially lower future cost escalations than would be experienced with the use of oil or natural gas.

CAPITAL COST ESTIMATES

The capital costs of plants A, B, and C were estimated using subsystem cost models based on the results of previous studies. These construction cost estimates were then adjusted to common-year dollars at start of construction. Financing cost and cost escalation during construction were computed to give an estimate of the total plant investment outlay at start of operation.

The cost estimating model of each subsystem is a power law scaling relationship that gives the capital cost as a function of a single variable which is an appropriate measure of the size of the subsystem. The basis for the cost estimates of the gasifier subsystem and the combined-cycle subsystem is the oxygen-blown Texaco gasifier combined-cycle system, case EXTC, of reference 6. The cost of the gasifier subsystem is scaled according to its coal input; the cost of the combined-cycle subsystem is scaled according to the gross electrical power output of the combined-cycle with zero steam extraction from the steam turbine. The capital cost of the hydrogen production subsystem is scaled according to a relationship given in reference 7. This relationship gives the subsystem cost as a function of the electric power required to liquefy the hydrogen. The amount of liquid hydrogen produced is related to the liquefaction power by the conservative value of 5 kW-hr/lb of hydrogen.

The subsystem capital cost estimates determined with the cost models are expressed in dollars of several different years, depending on the source. These model estimates were adjusted to common-year dollars (start of construction, mid-1984) using escalation rates from reference 8. These escalation rates are: 1975 to mid-1978, 6.5 percent; and mid-1978 to mid-1981, 10 percent. A value of 6 percent was chosen for mid-1981 and beyond. This rate was chosen to be consistent with the general inflation rate assumed for the economic evaluation (next section).

The capital cost estimates for each subsystem include direct material and installation labor costs, indirect field labor cost, engineering and support costs, and a contingency allowance. Table IIIa lists the items included in each subsystem. Table IIIb lists the capital cost estimates for the three plant sizes studied. It also shows the construction cost adder for a 3-year construction period and base financing conditions (discussed in the next section).

Table IIIb shows that the increase in capital cost of the polygeneration plants A and B over the cogeneration plant C is mainly a result of the increased gasifer size and the addition of the hydrogen production

subsystem. As has already been seen above, the combined-cycle subsystems of the polygeneration plants are only slightly larger than the combined-cycle subsystem of the cogeneration plant. The contribution of the combined-cycle subsystem to the increase in capital cost of the polygeneration plants over the cogeneration plant is small, as table IIIb indicates.

Figure 4 compares the capital cost of IGCC cogeneration systems obtained using the cost models described above with cost estimates obtained for such systems in a number of other studies. The capital cost is plotted versus the gross electrical power output with zero steam extraction so that cogeneration plants with different power to heat ratios may be shown on a single plot. The dashed line gives the capital cost as determined from the cost models. Shown on this line is case EXTC from reference 6 on which the gasifier and combined-cycle subsystem cost models are based and plant C from this study. The cost estimates from the other studies have been put in terms of the same-year dollars using the escalation rates quoted above and are all slightly lower than the cost model estimates. The cost models may thus be considered on the conservative side in relation to the conclusions of these other studies.

Estimates were also made of the operating and maintenance (O&M) costs for each of the plants studied. The O&M estimates for the gasifier and combined-cycle subsystems are based on the estimating procedure of reference 4. The two components of the annual O&M cost were treated separately. The fixed portion of the O&M costs (the portion independent of how much of the time the plant is in operation, that is, capacity factor) is proportional to the estimated total overnight capital costs of the subsystems. The variable portion of the O&M costs was scaled from the reference case according to the annual coal input to the gasifier and the capacity factor. Both components of the O&M cost for the hydrogen production system have been scaled from O&M cost estimates given in reference 10 according to the amount of liquid hydrogen produced.

ECONOMIC COMPARISONS

Economic Assumptions

The assumptions used in the economic evaluation are listed in table IV. General economic and market factors are tabulated in part (a) of table IV. Specific factors assumed for the IGCC plants are tabulated in part (b).

Annual revenue requirements over the life of the project are expressed in current-year dollars. As indicated in table IV(a), a general inflation rate of 6 percent per year was assumed. The comparative evaluation of the systems is insensitive to the assumed inflation rate if the relationship of finance rates and inflation rate is maintained. A rate of 6 percent was chosen as a representative long-term inflation rate that is consistent with the compound annual rate for a variety of inflation indices over the past 20 years based on historical price indices of references 11 and 12.

The assumed 1987 prices of coal and each of the output products are tabulated. Each of these prices is assumed to escalate above general inflation at the rates shown. These escalation rates (or real increases in product value) were chosen on a relative basis. Oil and natural gas prices are expected to increase faster than electricity prices. Coal prices are expected

to increase least. Since present commercial production of liquid hydrogen is largely dependent on natural gas feedstocks, the market price of liquid hydrogen was assumed to escalate at a rate comparable to oil and natural gas. The assumed base prices and escalation rates were varied parametrically, as indicated in table IV(a), in order to determine the sensitivity of the economic comparisons to these assumptions.

The base 1987 prices of coal, electricity, and oil were established by escalating typical 1981 prices by the base escalation and inflation rates. The 1981 prices used are $2.00/MBtu for coal, $0.05/kW-hr for electricity, and $7.00 /MBtu for oil. These are representative of the range of price experienced in various regions in 1981 (ref. 13).

Commercial liquid hydrogen prices in 1980 were $1.70 to $1.90 per pound for small quantity purchases (ref. 14). These prices are very dependent on the costs of natural gas, electricity, and transportation. The base 1987 price of $2.00 per pound of table IV(a) is probably low, since it corresponds to $1.10 per pound in 1980 if the 1987 price is deescalated. The comparison of the polygeneration configurations of plants A and B to plant C is sensitive to the price of hydrogen. Because of this sensitivity to liquid hydrogen price, as well as the uncertainty in future escalation rates for currently required feedstocks, a range of liquid hydrogen prices was considered around the chosen base price. The range considered is biased toward lower prices since the polygeneration results are attractive at the base price assumption.

As shown in table IV(b), a 3-year design and construction period was assumed, with start of operation in mid-1987. The 3-year period is consistent with the findings of reference 1. Payments according to an assumed construction period cash flow curve were assumed to be made at the end of each year and final payment made at the end of the period. The financial guidelines of the project (discussed below) for target return on equity, interest on debt, inflation, debt-to-equity ratio, etc., were followed during this period. Investment tax credits were taken for progressive payments during construction.

Private ownership of the plant was assumed, with a 70 percent debt - 30 percent equity financing. This is typical of assumptions made in previous studies (ref. 9) and with reported cogeneration projects (ref. 15). As indicated, the debt-to-equity ratio was parametrically varied.

Project life was set at 20 years and this period of time was also used for book depreciation. The required return on equity was assumed to be 15 percent after taxes (with parametric consideration of 20 percent), and the interest rate was assumed to be 10 percent. It should be emphasized that these last two assumptions are set in a 6 percent per year inflation environment.

An investment tax credit of 10 percent was used. Other currently available energy tax credits could increase the total tax credit to as much as 20 percent. No energy tax credit was included in light of the 1987 start of operation and the currently scheduled expiration of the Federal energy credit.

Tax depreciation was based on the accelerated cost recovery system (ACRS) schedule for post-1984 property as prescribed in the 1981 Economic Recovery Tax Act (ref. 16). The base life for tax purposes was 10 years, with

parametric consideration of 5 and 15 years. It is possible that parts of the IGCC polygeneration plant would qualify for shorter depreciation periods and, hence, the base 10-year tax life may be conservative.

Federal and State income taxes were assumed at a 50 percent composite rate; the annual expense of other taxes and insurance was taken as 3 percent of the initial investment.

An important parameter affecting the annual revenue requirement and its comparison with the market value of the products is plant capacity factor. A base value of 0.80 was assumed, with parametric consideration down to 0.50. This low value is of particular interest as an indicator of the effect on the economics during the early years of operation when lower plant availability might be anticipated.

IGCC System Revenue Requirement

The revenue required to operate each of the IGCC plants studied was calculated for each year of its operating life. The calculations were based on the performance and capital cost estimates presented in previous sections and on the economic assumptions given in table IV.

Table V gives an example of the results of these calculations. Shown are the revenue required for the first full year of operation for all three IGCC plants studied. The capital portion of the revenue required is proportional to the total capital cost estimates given in table III. It was calculated using the assumptions of table IV. It includes equity recovery, return on equity, payments on debt, Federal and State income taxes, and other taxes and insurance. The income taxes are reduced by tax depreciation calculated according to ACRS. The revenue required during the early years of the project life depends strongly on the assumed tax depreciation schedule and on the assumed debt to equity ratio. The impact of these assumptions is explored later.

The revenue required also includes revenue to cover the cost of coal and the O&M costs. These portions of the revenue required are calculated from the estimated plant performance and estimated O&M costs by assuming that the plant operates with a 0.8 capacity factor.

Table V also shows the potential market value of the products produced by each plant. For each plant, the market values are shown for two net steam extraction rates. The market values are based on the prices in table IV and on a 0.8 plant capacity factor. Table V shows that the total potential market value of the products is greatest for plant A which produces the most hydrogen. Also for each plant the total product market value is greater when net process steam is produced. The increase in the product market value resulting from increases in the production of process steam outweighs the decrease resulting from the smaller amount of electricity produced. For the electricity and steam prices assumed here, there is an economic incentive to extract process steam whenever it is required. This is the economic consequence of the fuel savings numbers shown in figure 3.

Table V shows that for the base economic assumptions the potential market value of the products exceeds the revenue required for all three plants during the first full year of operation. The margin between the potential

market value of the products and the revenue required is substantially greater for the polygeneration plants A and B than for the cogeneration plant C. For the polygeneration plants, the margin is near 50 percent of the potential market value of the products.

The revenue required and product market value will change with time. The market values of the three products escalate at different rates and the revenue required is affected by changes in time of such things as the tax depreciation. Figure 5 shows the revenue required and the potential market value of the products for each year of the project life for each of the three plants studied. Figure 5 uses the base value assumptions of table IV; later figures will illustrate the effect of variations from these base values. Each part of figure 5, corresponding to plants A, B, and C, respectively, shows the product market value for three different process steam extraction rates. Figure 5 shows that except for case C1 the relationships among the plants shown for the first full year of operation hold true over the operating life of the plants. The increase in the potential market value of the products for cases A and B over case C is greater than the increase in the revenue required. The margin between the potential market value of the products and the revenue required increases with increasing liquid hydrogen production.

For the purposes of this study, the margin between the potential market value of the products and the revenue required is used as an indicator of the potential attractiveness of the cases studied relative to one another. The precise definition or interpretation of this margin is not necessary here and is beyond the intended objective of this study. The interpretation of this margin depends on many technical, economic, and institutional factors. For example, a portion of this margin might be necessary to cover costs of distributing or transporting the products. Such costs will depend on the identity of the IGCC owner and customer(s). In cases where the margin is substantial, a large portion of the margin could represent additional savings or revenue to one or more of the parties involved in the ownership or operation of the plant. The margin or a portion of it could allow a higher return on equity than is assumed in the revenue requirement calculations. The margin could represent savings in the form of avoided cost for the purchase of products which are instead produced by the IGCC plant. It could also allow for significant flexibility in the pricing of the individual products of the IGCC plant by the owner.

Figure 6 shows the margin for each year of plant operation for the cases studied. Part (a) of the figure shows the margin in current dollars per year and part (b) shows it as a percentage of the assumed product market value for each year. Except for case C1, the revenue required each year increases at a much lower rate than the product market value resulting in a substantial increase in the margin with time.

The breaks in the revenue required curves of figure 5 and the curves of the margin between the revenue required and the product market value of figure 6 correspond to the end of the tax depreciation period. The tax depreciation lowers the revenue required and, thus, increases the margin during the early years of plant operation. The effect of the length of time over which the plant is depreciated is illustrated in a later figure. After the plant is fully depreciated, the capital portion of the revenue required, in current

dollars, is essentially constant in time. The escalation of the revenue requirement during this time depends on the price escalation of coal to fuel the plant and the O&M cost escalation. The large growth in the margin in the later years of the plant life is primarily a result of the differential escalation rates between the product market value and the revenue required. This too will be illustrated in a later figure.

Sensitivity Analysis

Two characteristics of any new technology plant that influence its economic attractiveness and about which there is obvious uncertainty are the estimate for capital cost and the estimate for the plant capacity factor during its early years of operation. Figure 7 shows the sensitivity of the first year margin between the potential market value of the products and the revenue required to the assumed plant capacity factor and to the capital cost estimate. The figure covers all the cases considered and is for the base economic conditions which include a 15 percent after tax return on equity as part of the revenue required. Part (a) of the figure gives the sensitivity of the first-year margin to the capacity factor. Except for case C1, the first-year margin is positive even for capacity factors of less than 50 percent. This means that the required return on equity could be achieved during the first year of operation even if, because of start-up problems, the capacity factor is much lower than the assumed base value.

Part (b) of figure 7 shows what happens to the first-year margin if the estimated capital costs of the plants considered are either decreased or increased. For plants A and B the first-year margin remains positive even for a doubling of the estimated capital cost. Also it can be seen that the margin for the polygeneration plants A and B remains greater than that for the cogeneration plant C even for a large increase in the estimated capital cost of the polygeneration system relative to the cogeneration system.

Figure 8 examines the effect of changes in the assumptions concerning the IGCC plant financing. Each part of the figure shows the effect on the annual revenue required for plant B of changes in one assumption while the remaining assumptions are left unchanged. The figure also gives the potential market value of the products for the three plant B cases so that the effect of the changes in assumptions on the margin between the market value and the revenue required can be seen. This figure indicates the significant effect the specific financial arrangements can have on the attractiveness of any cogeneration or polygeneration project, particularly during the earlier years of the project. Since, as shown in figures 5 and 6, the polygeneration plants have a higher margin between the revenue required and the potential product market value, the range of conditions over which they might remain attractive should be larger than for cogeneration plants.

Part (a) of figure 8 varies the assumed debt-to-equity ratio. Since the target after-tax return on equity is greater than the after-tax cost of debt, an increase in the proportion of equity means that the revenue required increases over most of the life of the plant. An increase in the proportion of equity has the most effect on the margin between the product market value and the revenue required during the early years of plant operation. With the assumption of 70 percent equity, the revenue required exceeds the assumed product market value during the early years of operation.

Part (b) of figure 8 shows the effect on the results if it is assumed that a higher return on equity is required to attract sufficient equity capital. An increase in the return on equity from 15 percent to 20 percent reduces the first-year margin between the revenue required and the market value of the products for case B1 by about a third.

Figure 8(c) compares the revenue required for different tax depreciation schedules. The figure shows results for 5-, 10-, and 15-year ACRS depreciation schedules. Part of the IGCC facilty may be required to use or qualify for one or another of these schedules depending on ownership or commercial status. The more rapid depreciation schedules dramatically increase the margin between the market value and the revenue required during the early years of operation but decrease the margin during the middle portion of the plant operating lifetime.

Figures 9(a) to (d) explore the impact of changing the values of the assumed market prices of liquid hydrogen and electricity, the purchase price of coal, and the rate at which these prices escalate in comparison with general inflation. All four parts of figure 9 treat case B2, and show the revenue required and product market values for different price assumptions. Part (a) of the figure varies the first-year (1987) liquid hydrogen market price and part (b) varies the first-year electricity market price. All prices except the one varied are held fixed at their base value. Even over the rather wide range in prices, the margin between the product market value and revenue required remains substantially positive indicating that the target return on equity could be achieved.

Figure 9(c) varies the first year price of coal. This affects the revenue required rather than the product market value. Again, the margin between the product market value and the revenue required remains positive by a substantial amount over a wide range of coal prices.

The last part of figure 9 shows the effect of varying the assumed escalation rates of coal, electricity, and liquid hydrogen relative to general inflation. The base escalation rates of these commodities relative to general inflation ("real escalation") were assumed to be 1, 2, and 3 percent, respectively. Figure 9(d) shows the results for these base rates (solid lines), for zero real escalation of all prices (dashed lines), and for a combination of intermediate values (dot-dash lines). Higher real-price escalation rates of the products can increase the margin between the product market value and revenue required significantly during the later years of plant operation. Even zero real escalation rates still give a greater margin during the later years than the early years, but the growth in the margin is much smaller.

Individual Product Costs

In previous sections the overall revenue requirement of the system was compared to the potential market value of the products for each year of the project. While the potential market value of the products was derived from estimates of the individual product market prices, the total system revenue requirement was not allocated between the products to estimate their individual production costs. The total revenue required for the plant could be obtained for a range of relative costs assigned to the individual products.

As an example, the range of relative costs which could be associated with the two products of the IGCC cogeneration plant C is shown in figure 10 for the first year of operation. The lines on this figure give the locus of all combinations of per-unit cost for steam and electricity which will just meet the total plant revenue requirement for cases C2 and C3. The slopes of the lines differ because of the different relative amounts of electricity and steam produced by the two cases. The previously assumed market prices for steam and electricity for the first year of operation are shown for reference. Since the calculated revenue requirement is less than the market value of the products, the lines are closer to the origin than the point representing the assumed market values and there is a range of steam and electricity costs where both are below the assumed market prices. As this example shows, if the cost assigned to the electricity is equal to its market price, the effective cost of steam is less than $4/MBtu, considerably below its market price which depends on the cost of oil. On the other hand, if the cost of steam is assigned a value equal to its market price based on the use of oil, the effective generation cost of electricity would be considerably below its market price.

For plants A and B which produce three products, a three-dimensional version of figure 10 could be constructed. Figure 11 is one plane of such a three-dimensional figure. In figure 11 the process steam output is assigned a cost equal to its market price based on the use of oil. Plant A which produces 20 tons per day of liquid hydrogen is considered in figure 11(a) and plant B which produces 10 tons per day of liquid hydrogen is considered in figure 11(b). Shown is the locus of all combinations of per-unit cost of liquid hydrogen and electricity which will just meet the system total revenue requirement after the net process steam produced is assigned the value indicated. Again the assumed market prices for this first year of operation are shown for comparison.

As figure 11 indicates, the potential generation cost for the liquid hydrogen for the IGCC polygeneration system is considerably below the expected range of market prices based on conventional production from natural gas. If the electricity were assigned a cost equal to its market price, the liquid hydrogen production cost is reduced by more than 50 percent from its assumed 1987 market price. Such comparisons would vary from year to year of plant operation because, as figures 5 and 6 show, the margin between the revenue requirement and the market value of all the products varies from year to year. These figures also show that for most of the cases considered the comparisons become more attractive with time.

CONCLUDING REMARKS

An IGCC system which simultaneously produces electricity, process steam, and liquid hydrogen has been evaluated. This system has been compared to a similar IGCC system that cogenerates electricity and process steam. The intent of the analysis was to identify and quantify the potential benefits of such an IGCC polygeneration system. For this reason, a range of liquid hydrogen and steam production rates and a range of economic parameters were considered. The evaluation of the polygeneration system was not done for a specific site or for a specific application, but the ranges of parameters considered was broad enough to allow a preliminary assessment for specific sites.

All the IGCC cases analyzed assumed the use of a 15 MWe gas turbine. Since the combined cycle supplies all the internal power required by the IGCC plant as well as the process steam, the net electrical power available varies with the amount of process steam and liquid hydrogen produced.

The approach taken to evaluate the relative attractiveness of the IGCC cases considered was to calculate the annual revenue required for each case and to compare it to the potential market value of the products for that case. This approach allowed a convenient and consistent comparison of cases that produced different amounts of multiple products. It was not necessary to allocate costs among the multiple products. It was also not necessary to consider a specific site or a specific ownership option.

The results show a substantial margin between the revenue required and the potential market value of the products for the IGCC polygeneration systems. This margin indicates that the return to the owner could be substantially higher than the target return assumed in calculating the revenue required. It also indicates that, for the assumed return, the products could be generated at a substantially lower cost than their assumed market prices.

This margin between the revenue required and the product market value is much larger for the polygeneration cases than for the cogeneration cases. For the polygeneration cases, the margin remains for wide variations in the assumed price for coal and the assumed market prices of electricity, steam, and liquid hydrogen. The margin remains for substantial increases in the capital cost estimate or for relatively low capacity factors during the first year of operation.

The IGCC systems show a fuel savings in comparison to the conventional separate production of its products. This is primarily a result of the generation of steam from otherwise waste heat. But even more significant is the likelihood that the coal used in the IGCC system would displace the oil or natural gas used to produce steam in an on-site boiler and the natural gas used as a feedstock to produce hydrogen. Since oil and natural gas will probably escalate in price faster than coal, the IGCC polygeneration system's economic attractiveness would increase with time.

There are other aspects and potential advantages of IGCC polygeneration which have not been considered in this preliminary analysis but which could and should be considered in a site specific study. These include:

(1) Consideration of system configuration variations and available equipment which might be more appropriate for the particular loads of a site.

(2) Consideration of time variations of the site loads or requirements and how the system can be most economically operated under these conditions.

(3) Consideration of the potential for economic utilization of other system outputs that were assumed to be discarded in this preliminary analysis. These could include the elemental sulfur produced by the gas clean-up system, the gaseous nitrogen produced by the air-separation unit, and the carbon dioxide produced by the hydrogen production subsystem.

Because the IGCC system is environmentally clean and uses modular construction, it has the potential to provide for coal utilization and energy and cost savings in relatively small, dispersed, industrial applications. The use of a polygeneration configuration could substantially increase the economic attractiveness and, hence, increase the number of potentially attractive applications for the system.

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TABLE I. - MAJOR PARAMETERS OF IGCC CASES STUDIED

Coal type	Illinois No. 6, 3.4 percent Sulfur
Gasification subsystem	Entrained bed, Pressurized gasifier
	Oxygen blown
	Cold gas desulfurization
Gas turbine	
Firing temperature, ^{o}F	2000
Compressor pressure ratio	12
Gross power output, MWe	15
Steam turbine	
Type	Extraction
Throttle temperature, ^{o}F	750
Throttle pressure, PSIG	600
Extraction pressure, PSIG	
Shift reactor steam	500
Process steam	200
LH_2 Output rate, ton/day	0, 10, 20
Net process steam output, MWt	0, 10, 20

TABLE II. - IGCC SYSTEMS STUDIED

	Liquid H_2 tons/day	Gross power rating, MWe	Coal input tons/day	Net process steam, MWt	Net power output, MWe
PLANT A					
Case A1	20	27.2	350	0	12.4
Case A2				10	10.0
Case A3				20	7.6
PLANT B					
Case B1	10	26.2	284	0	17.0
Case B2				10	14.6
Case B3				20	12.1
PLANT C					
Case C1	0	25.9	219	0	21.6
Case C2				10	19.1
Case C3				20	16.7

TABLE III. - CAPITAL COST ESTIMATES

(a) Items included in each subsystem

Gasifier subsystem

- Coal handling
- Air separation plant
- Oxidant feed
- Gasifier
- Ash handling
- Gas cooling
- Particulate removal
- Acid gas removal
- Sulfur recovery
- Tail gas treatment
- General plant facilities

Combined cycle subsystem

- Gas turbine
- Heat recovery steam generator
- Steam turbines
- Condenser
- Boiler feedwater circuit
- General plant facilities

Hydrogen production subsystem

- Gas shift converter
- CO_2 scrubber
- Hydrogen liquefiers and refrigerators
- General plant facilities

General plant facilities include

- Roads
- Buildings
- Railroad loading and unloading
- Electrical distribution
- Electrical substations
- Cooling water systems
- Inerting systems
- Instrument air systems
- Laboratories
- Effluent water treatment
- Etc.

TABLE III. - Continued.

(b) Estimates by subsystem

	Plant A	Plant B	Plant C
Gasification subsystem			
Total installed cost	35.32	29.92	24.26
Contingency	6.50	5.50	4.46
Subsystem total	41.82	35.42	28.72
Combined cycle subsystem			
Total installed cost	28.94	28.14	27.32
Contingency	5.66	5.50	5.34
Subsystem total	34.60	33.64	32.66
Hydrogen production/liquefaction			
Total installed cost	7.61	3.86	0
Contingency	2.15	1.09	0
Subsystem total	9.76	4.95	0
Subtotal (mid-1984 $, millions)	86.18	74.01	61.38
Construction adder (base case financing) 3-year construction period	10.96	9.41	7.80
Total (mid-1987 $, millions)	97.14	83.42	69.18

TABLE IV. - ECONOMIC PARAMETERS

(a) General

Item	Base value	Variations considered
General inflation rate, percent	6	--
Prices at end of 1987 (in 1987 dollars)		
Coal, $/MBtu	3.00	--
Electricity, $/kWH	.08	.06 to .12
Steam, $/MBtu	15.00*	
Liquid Hydrogen, $/lb	2.00	1.2 to 2.4
Escalation above inflation, percent		
Coal	1	0
Electricity	2	0, 1
Steam	3	0, 1
Liquid hydrogen	3	0, 1

*Based on oil price of 12 $/MBtu

Table IV. - Continued.

(b) Specific to IGCC system

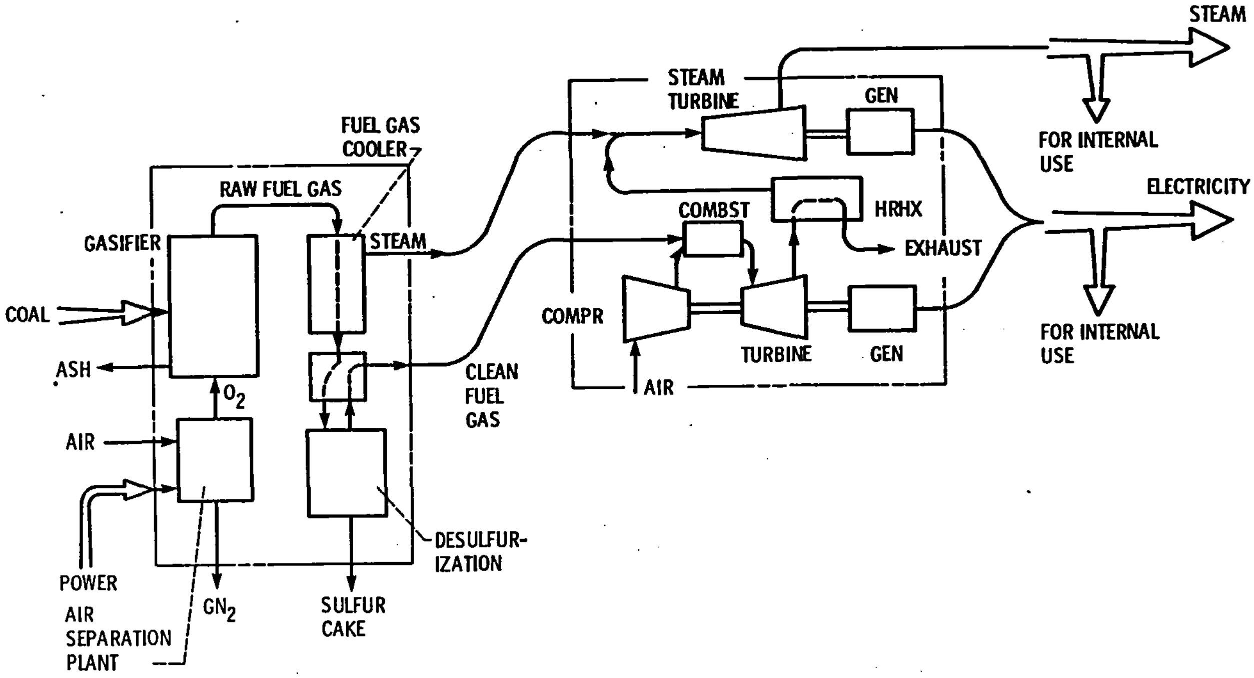
Item	Base value	Variations considered
Start of construction	Mid-1984	--
Start of operation	Mid-1987	--
Return on equity, percent	15	20
Interest rate, percent	10	--
Debt/equity ratio	70/30	30/70, 50/50
Investment tax credit, percent	10	--
Tax depreciation	*ACRS	--
Tax life, year	10	5, 15
Federal and State income tax, percent	50	--
Other taxes and insurance, percent of investment	3	--
Project life, year	20	--
Capacity factor	0.8	0.5 to 0.9

*Accelerated Cost Recovery System, 1981 Economic Recovery Act

TABLE V. - REVENUE REQUIRED, POTENTIAL MARKET VALUE OF PRODUCTS, AND MARGIN BETWEEN THEM FOR FIRST FULL YEAR OF OPERATION AND BASE ECONOMIC AND MARKET CONDITIONS

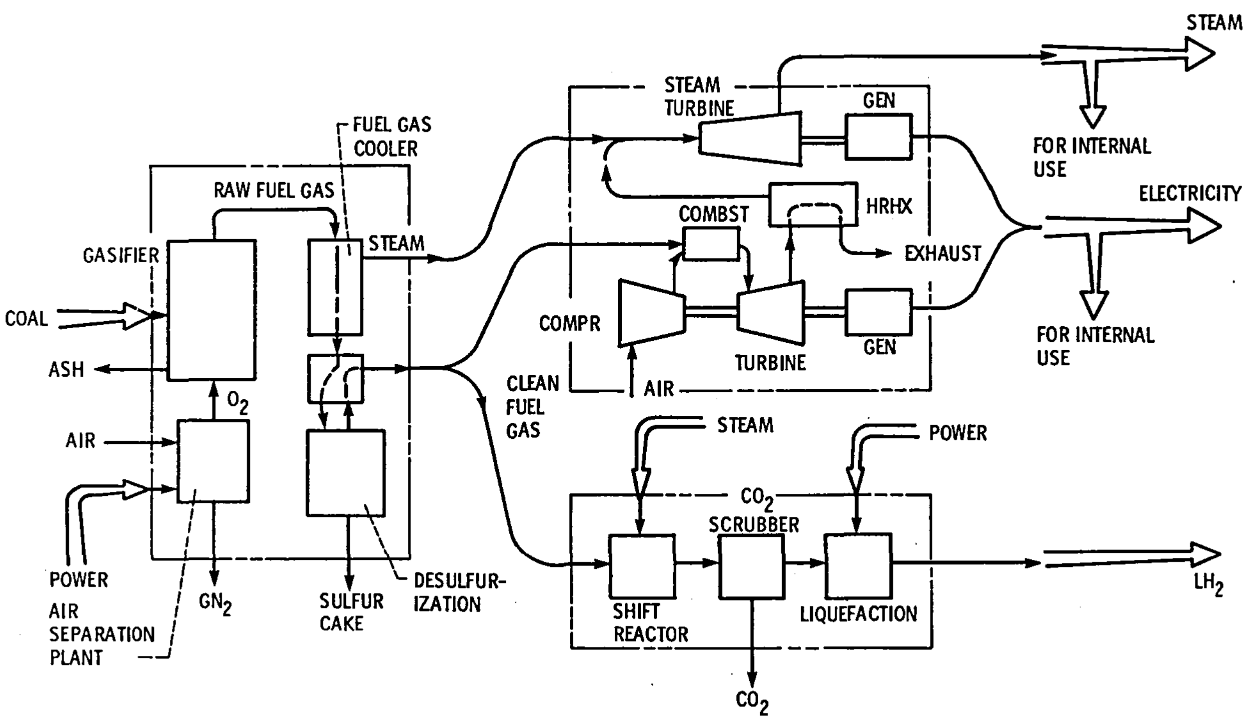
	Plant A	Plant B	Plant C
Revenue Required			
Capital	7.7	6.6	5.5
O&M	3.2	2.7	2.2
Coal	8.0	6.5	5.0
Total	18.9	15.8	12.7

	Case A1	Case A3	Case B1	Case B3	Case C1	Case C3
Potential Market Value of Products						
Electricity	7.5	4.6	10.3	7.3	13.1	10.1
Steam	0	8.1	0	8.1	0	8.1
Liquid hydrogen	25.5	25.5	12.8	12.8	0	0
Total	33.0	38.2	23.1	28.2	13.1	18.2
Margin, 10^6 \$	14.1	19.3	7.3	12.4	0.4	5.5
percent of Market value	43	51	32	44	3	30



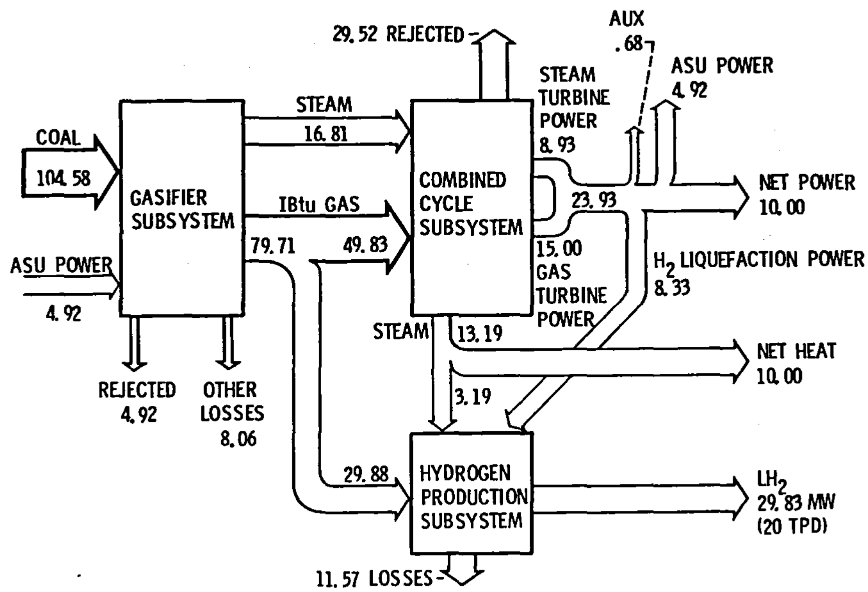
(a) Cogeneration: power and process steam.

Figure 1. - IGCC system schematic.



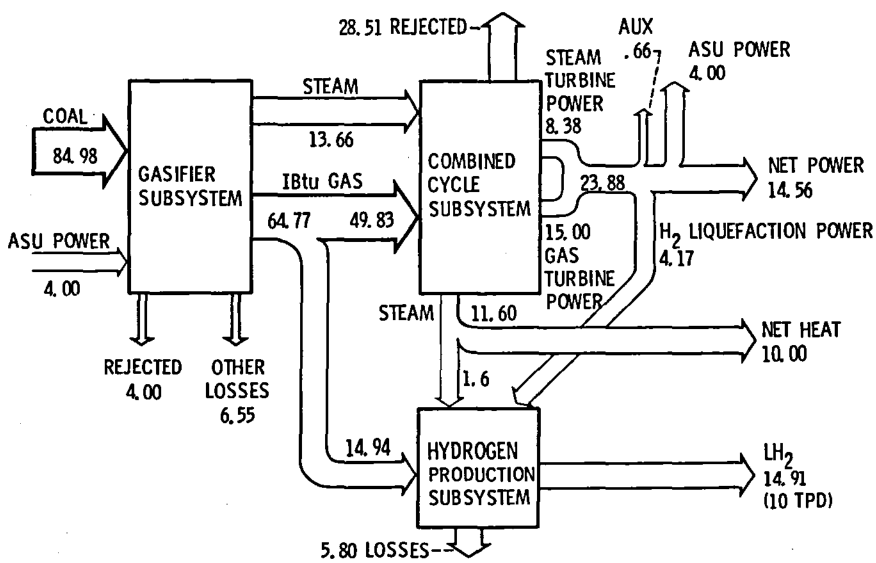
(b) Polygeneration: power, process steam, and liquid hydrogen.

Figure 1. - Concluded.



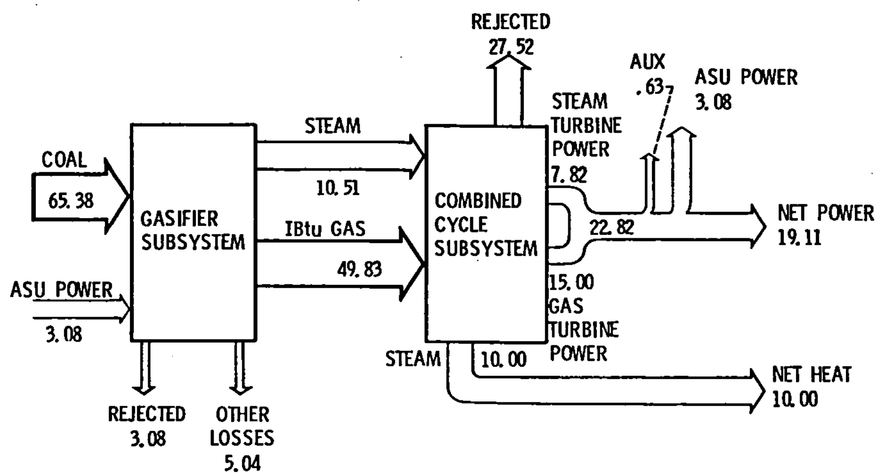
(a) Plant A.

Figure 2. - Energy flow diagrams for the IGCC plants considered, 10 MW of net process steam.



(b) Plant B.

Figure 2. - Continued.



(c) Plant C.

Figure 2. - Concluded.

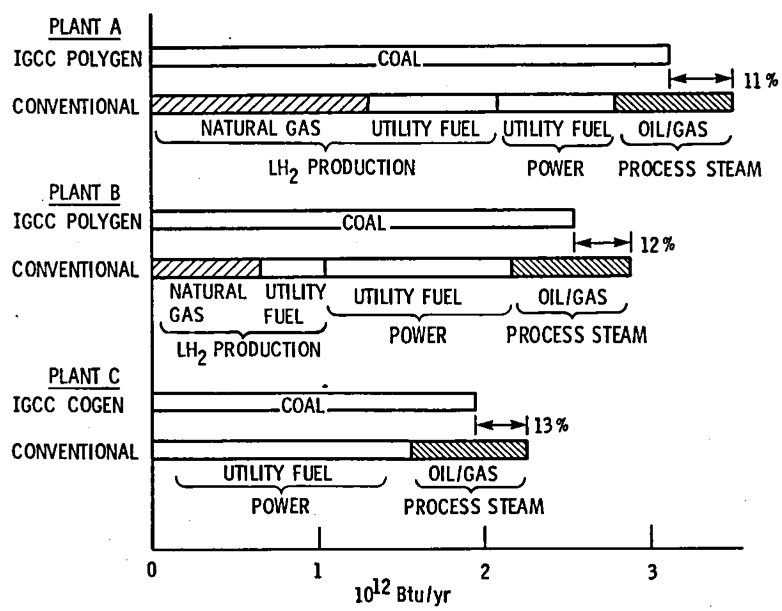


Figure 3. - Comparison of fuel use for IGCC polygeneration plants and conventional generation of products, for 20 MW of net process steam.

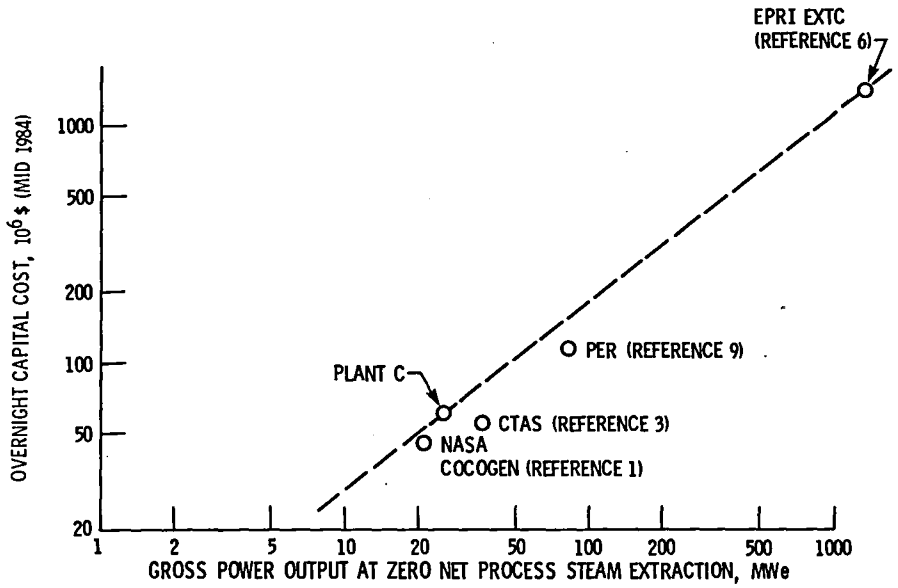
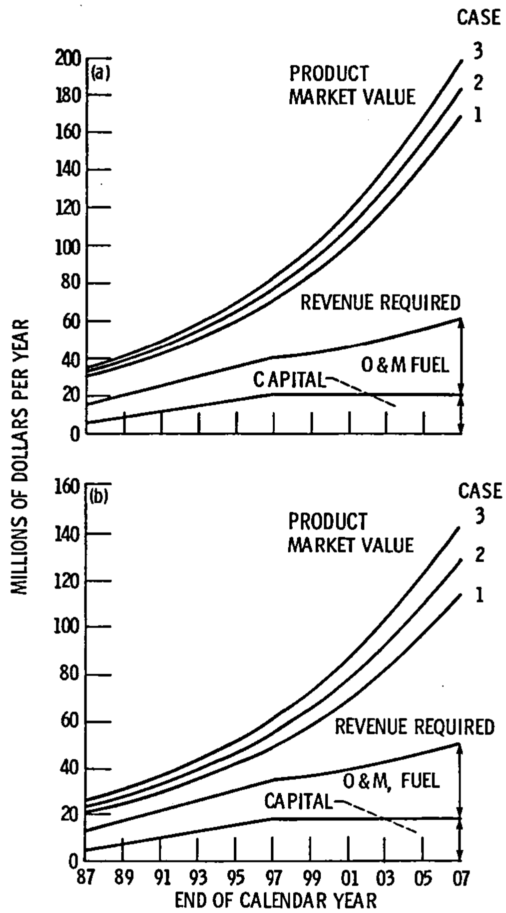


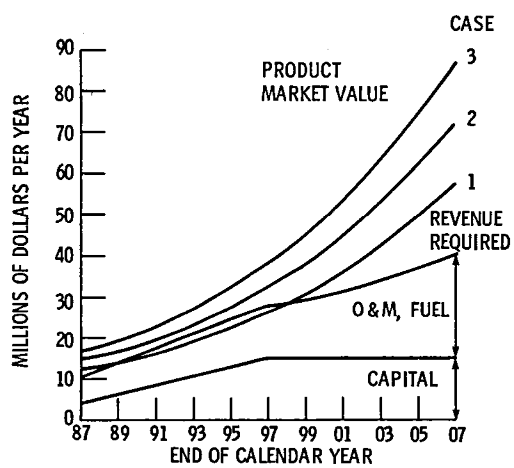
Figure 4. - Comparison of capital cost estimate for IGCC plant C and capital cost estimates from previous IGCC cogeneration studies.



(a) Plant A.

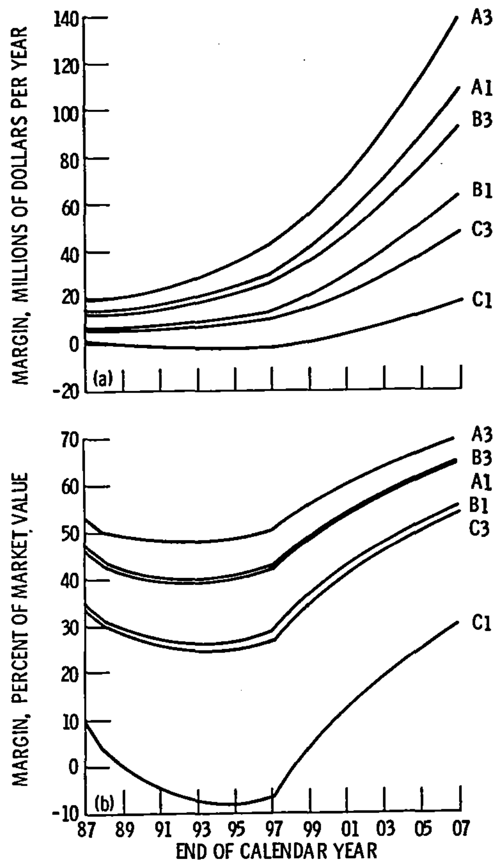
(b) Plant B.

Figure 5. - Comparison of revenue required and market value of products vs time for base economic and market conditions.



(c) Plant C.

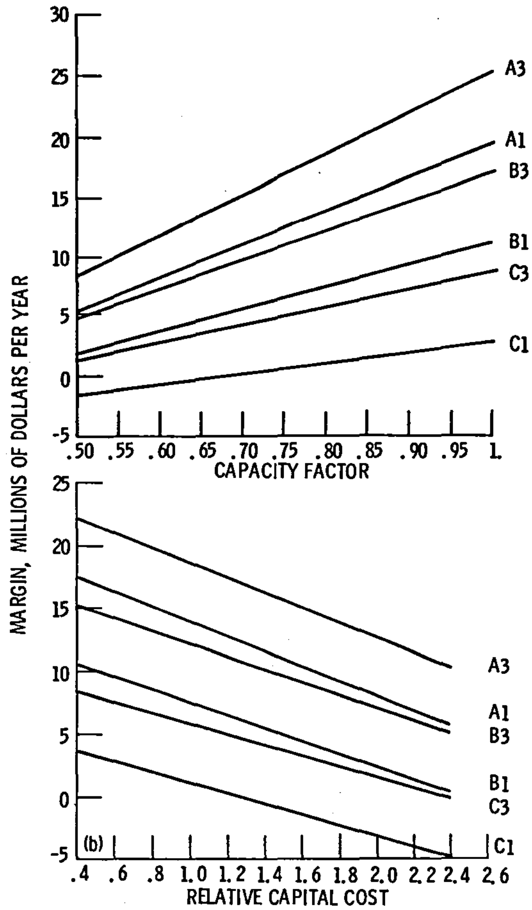
Figure 5. - Concluded.



(a) Margin in 10^6 \$/yr.

(b) Margin as percentage of product market value.

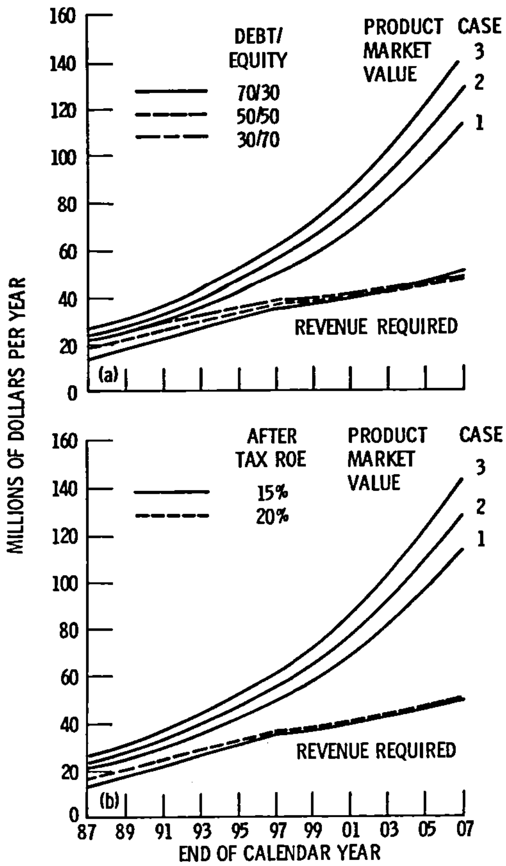
Figure 6. - Comparison of margin between revenue required and market value of products for cases studied for base economic and market conditions.



(a) Capacity factor.

(b) Estimated capital cost.

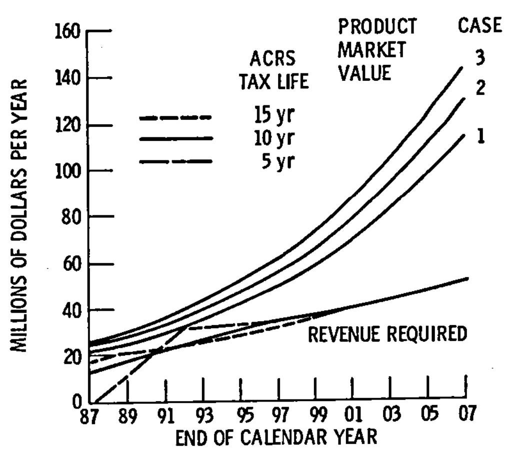
Figure 7. - Sensitivity of first-year margin to IGCC plant characteristics.



(a) Debt to equity ratio.

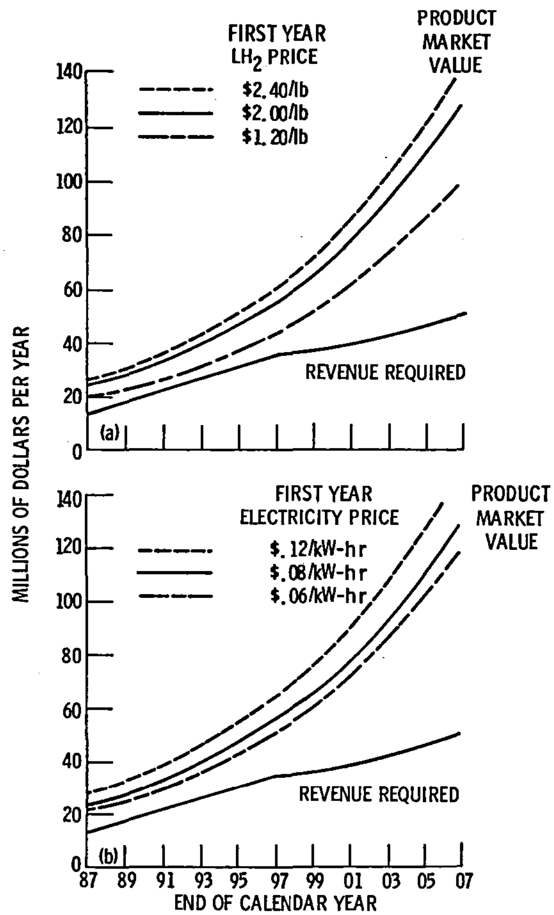
(b) Return on equity.

Figure 8. - Sensitivity of revenue required to economic assumptions for plant B.



(c) ACRS tax life.

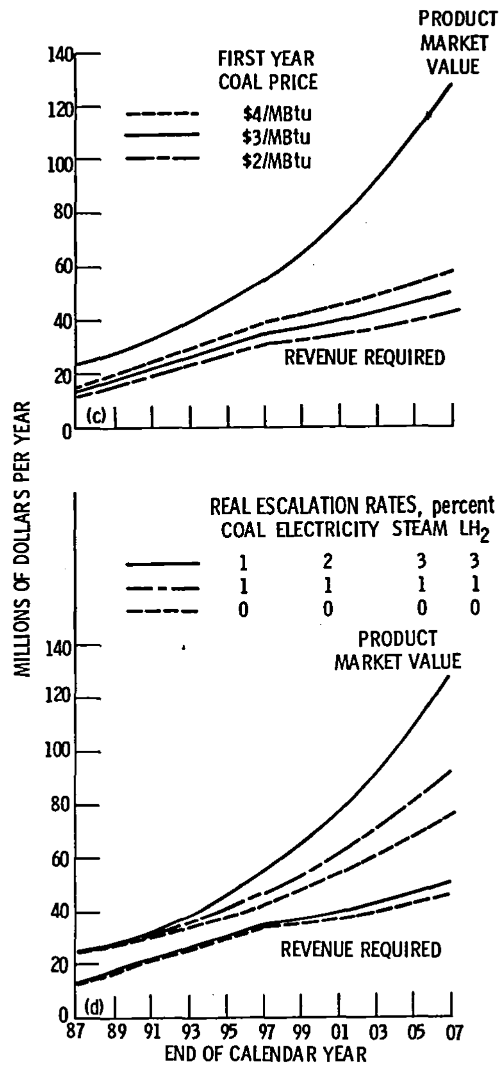
Figure 8. - Concluded.



(a) Market price of liquid hydrogen.

(b) Market price of electricity.

Figure 9. - Sensitivity of results to assumed prices and escalation rates for plant B.



(c) Price of coal.

(d) Escalation rates.

Figure 9. - Concluded.

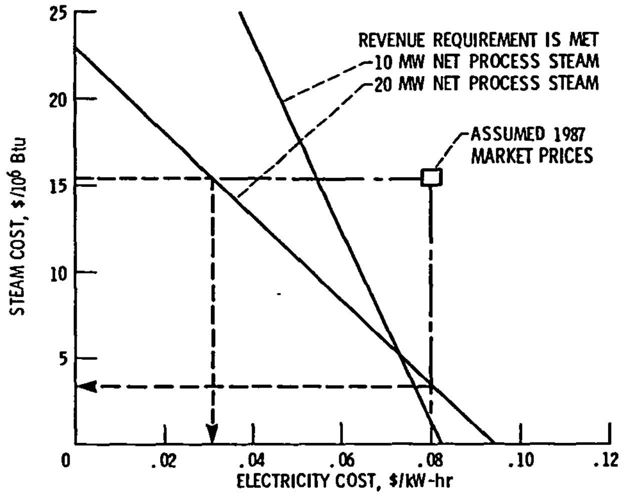
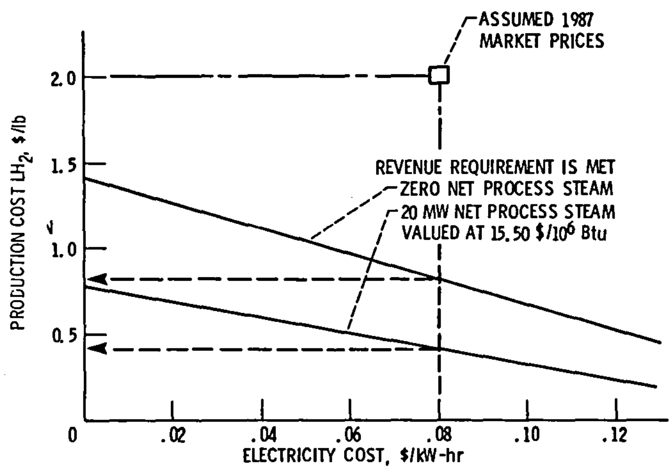
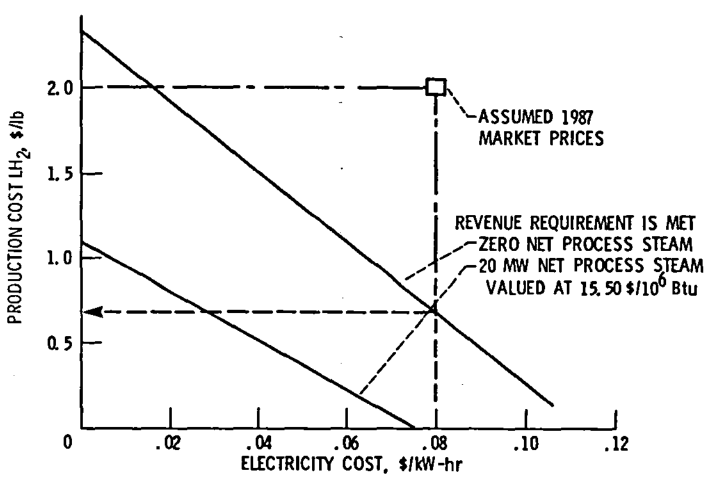


Figure 10. Product cost allocations for IGCC cogeneration plant C for the first year of plant operation.



(a) Plant A.

Figure 11. Product cost allocations for IGCC polygeneration plants for the first year of plant operation.



(b) Plant B.

Figure 11. - Concluded.

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16. Abstract

An integrated gasifier combined cycle (IGCC) system which simultaneously produces electricity, process steam, and liquid hydrogen was evaluated and compared to IGCC systems which cogenerate electricity and process steam. A number of IGCC plants, all employing a 15 MWe has turbine and producing from 0 to 20 tons per day of liquid hydrogen and from 0 to 20 MWt of process steam were considered. The annual revenue required to own and operate such plants was estimated to be significantly lower than the potential market value of the products. The results indicate a significant potential economic benefit to configuring IGCC systems to produce a clean fuel in addition to electricity and process steam in relatively small industrial applications.

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